# An Experimental Study of the Influence of Interfacial Tension on Water–Oil Two-Phase Relative Permeability

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Abstract Adding surfactant into the displacing aqueous phase during surfactant-enhanced aquifer remediation of NAPL contamination and in chemical flooding oil recovery significantly changes interfacial tension (IFT) ( $\sigma$ ) on water–oil interfaces within porous media. The change in IFT may have a large impact on relative permeability for the two-phase flow system. In most subsurface flow investigations, however, the influence of IFT on relative permeability has been ignored. In this article, we present an experimental study of two-phase relativepermeability behavior in the low and more realistic ranges of IFT for water-oil systems. The experimental work overcomes the limitations of the existing laboratory measurements of relative permeability (which are applicable only for high ranges of IFT (e.g.,  $\sigma > 10^{-2}$  mN/m). In particular, we have (1) developed an improved steady-state method of measuring complete water-oil relative permeability curves; (2) proven that a certain critical range of IFT exists such that IFT has little impact on relative permeability for  $\sigma$  greater than this range, while within the range, relative permeabilities to both water and oil phases will increase with decreasing IFT; and (3) shown that a functional correlation exists between water-oil twophase relative permeability and IFT. In addition, this work presents such correlation formula between water-oil two-phase relative permeability and IFT. The experimental results and proposed conceptual models will be useful for quantitative studies of surfactant-enhanced aquifer remediation and chemical flooding operations in reservoirs.

**Keywords** Interfacial tension  $\cdot$  NAPL  $\cdot$  Relative permeability  $\cdot$  EOR  $\cdot$  Surfactant-enhanced aquifer remediation  $\cdot$  Two-phase displacement  $\cdot$  Chemical flooding

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# **1** Introduction

In the past few decades, the petroleum industry has faced increasing technical challenges with the growing demand for oil and natural gas, while at the same time few new oil reserves have been found worldwide. Consequently, more efficient development of oil and gas from existing reservoirs, using enhanced oil recovery (EOR) methods, has been listed as a top priority within research efforts in the energy industry. Since the 1970s, as a result of industry-wide efforts to improve oil recovery rates, many EOR techniques have been developed and applied to various oil fields. In general, EOR methods, such as chemical flooding, miscible flooding, such as CO<sub>2</sub> flooding, and thermal recovery techniques, rely on altering the mobility and/or the interfacial tension (IFT) between the displacing and displaced fluids to improve sweep or displacement efficiency. Among the various EOR approaches developed, chemical flooding, with various chemical surfactants and agents added into injected fluids, is among the most promising, cost-effective, and widely used for reservoirs with a long history of water flooding.

In addition to the concerns in the oil industry, cleaning up soil and groundwater contamination from nonaqueous phase liquids (NAPLs), such as from oil and gasoline leakage, has received serious attention since the 1980s. The physical processes associated with subsurface remediation of NAPL contamination are governed by the same fundamental laws that govern multiphase flow and transport in oil reservoirs. Recognizing this similarity, hydrologists and soil scientists have borrowed many techniques, such as surfactant and other chemical or thermal enhanced methods, developed initially for EOR operation in the petroleum industry, for efficient remediation of NAPL contamination (e.g., Falta et al. 1992; Sabatini et al. 1996; Saba et al. 2001; Zhong et al. 2003).

In order to evaluate such chemically enhanced EOR or cleanup approaches for their efficiency or suitability to a given subsurface system, investigators resort to quantitative studies of laboratory experiments and field applications, requiring many physical parameters and constitutive correlations. Water-oil (or NAPL) two-phase relative permeability is perhaps the most important constitutive relation that characterizes two-phase flow and displacement processes in porous media. Because of the additional interactions between fluid (water and oil or NAPL) phases, chemical components, and solid porous rock, flow behavior within chemical flooding or EOR is in general more difficult to characterize than that within oil displacement in conventional water immiscible flooding. Even with the significant progress made in understanding chemical flooding over the past few decades, it remains a challenge to assess quantitatively such flow behavior. It is even more difficult to predict whether this technique can be successfully applied to a given field condition. One of the primary difficulties is the lack of physical insight or constitutive correlations (e.g., relative permeability curves) for describing mutual effects or interplay between phases during chemical flooding processes, a deficiency that hinders quantitative analysis (such as numerical modeling studies) of laboratory or field studies.

The primary goals in reservoir EOR operations or in chemically enhanced aquifer remediation of NAPLs are to displace or mobilize more remaining oil (or NAPLs) from existing formations than can be achieved using conventional water flooding or pump-and-treat techniques. Remaining oil left in reservoirs after long-time displacement recovery operations is normally discontinuously distributed in pores. From the viewpoint of fluid flow mechanics, there are two main forces acting on residual oil drops: *viscous* and *capillary* forces. Microscopic displacement efficiency with an EOR method depends on the relative influence or ratio of these two forces. Melrose and Brandner (1974) define capillary number as the ratio of viscous forces and capillarity

$$N_{\rm c} = \frac{\mu_{\rm w} V_{\rm w}}{\phi \sigma_{\rm wo}},\tag{1}$$

where  $N_c$  is the capillary number,  $\mu_w$  is the viscosity of aqueous or displacing phase,  $V_w$  is the flow velocity of the displacing phase,  $\phi$  is the effective porosity of formation, and  $\sigma_{wo}$  is the water–oil (NAPL) IFT.

Another useful parameter for quantitative analysis of NAPL cleanup or oil recovery operations is the microscopic displacement efficiency  $(E_m)$ , defined as

$$E_{\rm m} = \frac{1 - S_{\rm or} - S_{\rm wc}}{1 - S_{\rm wc}},\tag{2}$$

where  $S_{or}$  is residual oil (NAPL) saturation and  $S_{wc}$  is residual water saturation.

Using experimental results, Fulcher et al. (1985) show that changes in the capillary number have significant effect on the residual oil saturation of the system. The IFT between crude oil and in situ brine ranges from 20 to 30 mN/m under normal reservoir conditions, and the capillary number is at about  $10^{-6}$  for general water flooding reservoirs. The residual oil saturation is approximately at 0.4, and microscopic displacement efficiency of about 40% can be reached. As the capillary number rises to  $10^{-2}$ , however, the residual oil saturation could be lowered to near zero, and then recovery efficiency could theoretically be close to 100%.

One efficient way to increase the capillary number is adding surfactants to displacing fluids during chemical flooding operations, which could significantly reduce the IFT to as low as  $10^{-3}$  mN/m (equivalent a four-orders-of-magnitude increase in capillary number). This will increase the capillary number to above a value of  $10^{-2}$  for an optimal oil recovery result (Melrose and Brandner 1974). At the same time, water-phase relative permeability at residual oil saturation after waterflooding will continuously increase as the capillary number increases (Fulcher et al. 1985).

By altering IFT between water–oil (water–gas or oil–gas) phases, surfactants can cause significant changes in two-phase flow behavior. To understand the process, many researchers have studied relative permeability with flow systems involving change in IFT. Among the earlier efforts, Talash (1976) presented a modified Naar–Wygel equation, an exponential function, to describe the relationship between relative permeability and normalized saturation under low IFT conditions. By comparing with laboratory measurements, the modified model was found to fit well for relative permeability curves near the two ends of saturation ranges, but not well for the middle portion of the curves.

Lawson and Hirasaki (1983) published a more detailed study of flow behavior under low IFT. They found that two-phase water–oil flow and displacement behaved very differently with or without adding a surfactant. They showed that concentration, adsorption onto the rock, and partitioning of surfactants into the oleic phase all affected relative permeability curves. Asar and Handy (1988) measured relative permeability curves for two-phase flow of "oil" (methane, ethane, or kerosene) and gas (nitrogen) under different IFT, ranging from 0.033 to 30 mN/m. Based on shapes and extrapolations of measured relative permeability curves would become two diagonally straight lines (i.e., relative permeability equal to saturation) at zero IFT. This argument or prediction has received wide acceptance and has even been extended for flow in a water–oil system.

In addition, a number of studies indicate that there may exist a crucial IFT value below or above which the impact of IFT on relative permeability is very different. This hypothesis has been confirmed by results from investigating a low IFT water–oil system (Harbert 1983) and a low IFT oil–gas system (Bardon and Longeron 1980). Both studies found that relative permeability curves changed significantly when IFT is lower than 0.04 mN/m. For this low range of IFT values, their model appeared to fail. Using relative permeability curves measured from consolidated sandstone cores, Torabzadeh and Handy (1984) further categorized flow systems into a relatively high IFT system, with  $\sigma > 20$  mN/m, and a relatively low IFT system, with  $\sigma < 0.19$  mN/m. They considered that these were the two distinguishing zones of IFT in which relative permeability had different characteristics. Kumar et al. (1985) carried out more experimental studies, classifying IFT into three ranges for the relationships of residual oil or water saturation versus IFT. For high IFT with  $\sigma > 1.0$  mN/m, residual saturations are independent of IFT and are functions of temperature only. However, under lower IFT (0.15 mN/m  $< \sigma < 1.0$  mN/m) and an ultra-low tension system with  $\sigma < 0.150$  mN/m, two-phase residual saturations behave differently as functions of both temperature and IFT.

To overcome well-known difficulties in measuring relative permeability curves under low IFT, several attempts were made (Fulcher et al. 1985; Peters and Khataniar 1987; Chisholm et al. 1990), involving either increasing viscous forces in displacing fluids or increasing the capillary number. However, large increase in the viscosity of the displacing, aqueous phase may lead to too large decrease in displacing rates or mobility. On the other hand, very high flow rates will cause small rock solids or particles to migrate. As a consequence, those approaches cannot in general achieve the capillary number ranges appropriate for normal surfactant chemical flooding.

In addition to the effects of saturation, IFT, and temperature, relative permeability is also affected by pore structure or porous medium characteristics. To describe these effects, researchers have devoted considerable efforts toward deriving closed-form equations to correlate these factors with relative permeability functions (e.g., Fatt and Dykstra 1951). Brooks and Corey (1964, 1966) developed an equation that correlates capillary pressure with pore distribution and saturation, a closed-form equation that has been widely used ever since.

In the literature, a number of studies have been carried out regarding two-phase flow and displacement processes under different IFT values (Bardon and Longeron 1980; Chisholm et al. 1990; Asar and Handy 1988; Haniff and Ali 1990; Ronde 1992; Conway et al. 1985; McDougall et al. 1997; Mulyadi et al. 2002). The majority of these studies, however, were performed for either *oil–gas* or *water–gas*, not *water–oil* two-phase systems. Second, the ranges of IFT covered in these investigations were limited mostly to  $10^{-1}$  to 40 mN/m (or higher than  $10^{-2}$  mN/m). In addition, few studies have been conducted for the effect of IFT on relative permeability as a result of adding surfactants into water–oil systems. This is mainly because it is difficult to conduct such experiments and measurements (i.e., involving low IFT) under laboratory conditions, owing to the complexity in chemical-property effects and their variations, such as chemical reaction and adsorption.

In recent years, extensive studies from laboratory to field applications have been carried out in China for large-scale chemical EOR projects. In the 1990s, field pilot tests were carried out, using the alkali–surfactant–polymer combinational flooding approach, at several oil fields in China. As part of the field-application effort, laboratory studies of low IFT relative permeability for water–oil systems were also conducted. Using a dynamic method, Wang et al. (2002) and Lu et al. (2003) measured end values of relative permeability and remaining residual oil saturation for low IFT water–oil systems. They showed the effect of water–oil IFT on the end values of relative permeability under transient displacement. To avoid the large, undesirable effect of nonequilibrium adsorption of surfactants on relative-permeability, Ye et al. (2000) attempted to use a steady-state method for measuring end relative-permeability values, and made some useful findings regarding the effect of IFT on residual oil saturation. However, no complete relative permeability curves were obtained from that study because of the technical difficulties encountered in their measurements.

To fill the large gap between research and application regarding water-oil relative permeability under different IFT conditions, this article presents a detailed experimental study of the effects of low IFT on two-phase relative permeability in water-oil systems. In particular, we present an improved steady-state method for measuring water-oil relative permeability curves. The experimental results indicate that there may exist two critical IFT values that separate ranges of IFT effects on relative permeability and residual oil saturations. In addition, based on two-phase experimental data from sandstone cores, a two-phase relative permeability model is proposed to correlate water-oil two-phase relative permeability with IFT as well as saturations. The experimental results and proposed relative permeability model will be useful for numerical simulation and other quantitative studies of surfactant-enhanced chemical flooding operation in reservoirs.

### 2 Experimental Procedure and Method

To eliminate effects of complex chemical processes occurring at water–oil interfaces on measurements, we adopted a steady-state experimental method for measuring water–oil relative permeability within a low IFT system. The steady-state approach ensures that equilibrium is reached within the system for partitioning of chemical agents between water–oil phases and adsorption on rock solids.

# 2.1 Water-Oil System

# 2.1.1 Oil Phase

To make experiments as well as measurements repeatable, the oil or NAPL used in this study is called "model oil," or white oil. Note that the oil, designed according to the capillary number, is not actual crude oil from reservoirs. The model oil consists primarily of inactive normal paraffin hydrocarbons, extracted commonly from petroleum lubricant fluids through systematical treatment of removing light-hydrocarbon, wax, and volatile components (through filtering and depolarizing processes) and adding hydrogen. The treated oil is a colorless, nonvolatile, and nonsurfactant with a viscosity of about 1 cp. Also, it has stable chemical properties that will not change rock wettability, cause precipitation, or form colloids in cores.

# 2.1.2 Aqueous Phase

Brine, consisting of 5,000 mg/l of NaCl (sodium chloride), is used in the water–oil system as the aqueous phase. Using the high NaCl concentration brine reduces or eliminates the possible effect of the existence of clayey minerals of sandstone cores on capillary numbers on experimental results. In addition, a number of cores, which were completely dried under the higher temperature of 400–500°C, were used for comparisons with the results obtained using cores dried at 105°C. Comparative studies confirmed that the results with the selected cores gave stable experimental results without any indications of impacting on capillary numbers. It also serves as a base for constructing various low IFT fluid systems.

Fluid mixtures with low IFT used in EOR operations are usually composed of various chemical additives. When IFT is lower than  $10^{-1}$  mN/m for most fluid systems, different levels of emulsification will occur. This will make it difficult to measure relative permeabil-

ity curves. To resolve this problem, different combinations of chemical mixtures have been tested in this study, with the finalists screened and selected according to the following criteria:

- They enable ultralow IFT ( $\sim 10^{-3}$  mN/m) with both the model oil and crude oil from (1)reservoirs.
- The degree of emulsification has little impact on measurements of water and oil satu-(2)rations, in repeated use and after frequent flushing of cores.

Chemical components of the surfactant chosen for this study are: 2SY + NaCl (0.5 wt%) +NaOH (sodium hydroxide). Here, 2SY stands for alkyl benzene sulfonate, the main component of the surfactant, which in China is a widely used surfactant for chemical flooding agents in the laboratory.

# 2.2 Cores

Sandstone cores used in the experiment are made from outcrops located in Sichuan Province, China. These outcrop samples are well consolidated and have intermediate permeability ranges, which make them suitable for study of water-oil flow and displacement processes under different IFTs. Table 1 shows the basic properties of the 1-in. diameter cores used in this study. The main reason for selecting these outcrop cores is that the sandstone contains little (<1%) clayery or swollen materials, such as kaolinite and chlorite. In addition, rock solids of the cores show only a very weak adsorbing effect with the chemicals selected, which helps to minimize or avoid interference between chemicals and clayey minerals in measurement or analysis of flow behavior.

All the cores are thoroughly cleaned with liquid detergents to become strongly water wet. After cleaning, they are dried completely in an oven at 105°C until no change in weight is observed. In addition, several core examples, dried under the higher temperature of  $400-500^{\circ}$ C, have been tested to give similar results with those using  $105^{\circ}$ C dries cores.

Table 1         Parameters of core           samples used in experiments	Sample no.	Core length (cm)	Effective porosity	Permeability $(10^{-3} \mu \text{m}^2)$
	1-2	6.530	0.135	228
	1-1	6.522	0.140	237
	1-4	6.554	0.135	228
	1-3	6.487	0.135	256
	3-2	6.521	0.135	276
	2-1(fired)	6.558	0.131	273
	2-3	6.453	0.134	263
	2-4	6.474	0.133	281
	11-4	5.030	0.179	252
	3-1	6.426	0.142	333
	3-3	6.541	0.135	246
	11-2	4.987	0.191	168
	11-3	5.048	0.195	255
	3-4	6.517	0.134	226



Fig. 1 Schematic diagram of the apparatus and experimental setup

### 2.3 Measurements and Instruments

A flow chart of the experimental setup, instrumentation, and procedure of this experimental study is shown in Fig. 1. During experimental measurement of relative permeability curves by the steady-state method, we used two pumps (Quizix) to regulate injection, displacement, and recycling of water and oil fluids. Confining pressures within the cylindrical space were controlled by a separate manual hydraulic pump. In addition, several electromanometers with different measurement-scale ranges were employed to measure pressures at the inlet and outlet ends. Water and oil saturations were estimated by a mass-balance calculation using the scaled glass water–oil separator of Fig. 1. A tensometer (TX500C), based on a spinning-drop method, was used for measuring IFT.

Measurement errors in the experiments were all controlled within the ranges specified by the instrument used. In particular, volumetric errors introduced in measuring saturations are within  $\pm 0.005$  ml.

#### 2.4 Measurement of Relative Permeability

As discussed above, to account for the time needed for adsorption to reach equilibrium between chemicals and cores (i.e., to eliminate nonequilibrium sorption effects), we adopted a steady-state method in this study for measurement of relative permeability curves. Note that our steady-state method improves the traditional steady-state measurement in (1) accurate measurement of saturations under different emulsification conditions using a new instrument, installed at the outlet and (2) using one pump instead two.

In addition, only the cores with strong water wettability were selected, as determined by spontaneous imbibition indexes.

First, all the selected cores were fully saturated with a brine having a sodium chloride concentration of 4,500 mg/l. Then, water-phase permeability at zero oil saturation was measured from these 100% brine saturated cores.

To assure reaching adsorptive equilibrium between chemicals and cores at different saturations, we determined the first value of water saturation (i.e., a beginning minimum value of water saturation for the experiment) after more than 2 days of continuous injecting and recycling of the fluids through the core. By varying ratios of water and oil-injection rates at pumps, we adjusted increase in oil saturation gradually. Once a new steady state was reached, all parameters were measured and recorded, and relative permeability values for water and oil phases were then calculated by a steady-state Darcy flow.

Sample no.	Flow rate (ml/min)	Aqueous phase viscosity (cp)	Interfacial ten- sion (mN/m)	Capillary number
1-2 <sup>a</sup>	0.1	1	34.2 (Basis water and oil system without surfactant)	4.15×10 <sup>-5</sup>
1-1	1.0	1	,	$4.15 \times 10^{-4}$
1-3	0.1	10		$4.15 \times 10^{-4}$
1-4	1.0	10		$4.15 \times 10^{-3}$
3-2 <sup>a</sup>	0.1	1	3.52	$4.12 \times 10^{-4}$
2-1(fired) <sup>a</sup>	0.1	1		
2-3 <sup>a</sup>	0.1	1	0.21	$6.91 \times 10^{-3}$
2-4 <sup>a</sup>	0.1	1		$6.91 \times 10^{-3}$
11-4 <sup>a</sup>	0.1	1		$6.91 \times 10^{-3}$
3-1	0.1	10		$6.91 \times 10^{-2}$
3-3 <sup>a</sup>	0.1	1	0.0114	$1.27 \times 10^{-1}$
11-2 <sup>a</sup>	0.1	1		
11-3	0.1	1		
3-4 <sup>a</sup>	0.1	1	0.0023	$6.31 \times 10^{-1}$

 Table 2
 Flow rate and fluid parameters used in experiments

a Used in figures and analyses

There are a total of five fluid systems (Table 2) used in this study covering five different ranges of IFT.

# **3** Results and Discussion

# 3.1 Surfactant-Flooding Characteristics and Interfacial Tension

Experimental results indicate that there exists a certain correlation between residual oil saturation and water–oil IFT under different surfactant concentrations within core-fluid flow systems. With the selected water-wetting cores under laboratory temperature conditions, for example, there appear to be two crucial values ( $\sigma_{C1}$  and  $\sigma_{C2}$ ) observed for IFT (Figs. 2a, 3b). As shown in Fig. 2b, when  $\sigma > \sigma_{C1}$  (= 3 mN/m, the first or high crucial point), residual oil saturation of the water flooding remains at about 0.40. This residual saturation value of 0.40 seems to be unvarying with increases in IFT within this range. On the other end of the curve, as shown in Fig. 2b, residual oil saturation is also kept as a low-level constant for  $\sigma < \sigma_{C2}$  (= 0.01 mN/m). For the intermediate values of IFT (i.e.,  $\sigma_{C1} < \sigma < \sigma_{C2}$ ), however, Fig. 2 shows that residual oil saturation rapidly decreases with decreasing IFT. In other words, displacement efficiency increases significantly with lowering IFT. It should be mentioned that, as shown in Fig. 2a, b, there is the lack of experimental data points in the range of 0.01 <  $\sigma < 1$  (mN/m) and the behavior of residual oil saturation within this IFT range needs further investigation. However, Fig. 2 balso shows that there are more data points for lower IFT, which is the focus of the current study.



**Fig. 2** a Experimentally determined residual saturations as functions of the capillary number (or interfacial tension). **b** Experimentally determined residual saturations as functions of the interfacial tension

The relationship between residual oil saturation and IFT, under the different IFT of this study's core-fluid system, can be further quantified using a regression analysis. Fitting and statistical analysis of experimental data yields the following expression:

$$S_{\rm or} = \frac{\sigma_{\rm wo}^{1.5}}{A\sigma_{\rm wo}^{1.5} + B} \quad \left(r^2 = 0.9995, F_{\rm stat} = 5517\right),\tag{3}$$

where *A* and *B* are constants related to cores and experimental conditions (A = 2.432, B = 0.1154, fitted from our experimental data), and *r* and *F* are the correlation coefficient and *F*-test of statistics, respectively. As shown in Fig. 2, the results of using Eq. 3 (labeled as "fitted") match the experimental data points well.

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**Fig. 3** a Water–oil relative permeability as functions of the capillary number at water saturation of 0.5. **b** Water–oil relative permeability as functions of the interfacial tension at water saturation of 0.5

Relative permeability characteristics are observed to be very different under different IFTs for the studied water–oil systems. Figure 3 shows the experimental results of water–oil relative permeabilities and their variations under different values of capillary number (Fig. 3a) or IFT (Fig. 3b) at a constant saturation of  $S_w = 0.5$ . Note that when  $\sigma > \sigma_{C1}$  (=3 mN/m), water relative permeability is at about 0.08, and that oil relative permeability is at 0.2 at the water saturation value of 0.5. The two relative permeability values are almost constant over this range of the IFT. In contrast, relative permeabilities to both phases increase continuously as IFT decreases when  $\sigma < \sigma_{C1}$  (Fig. 3b). In general, the rate of increase in water relative permeability appears larger than that in oil relative permeability within the low range of IFT.

After fitting experimental data, we have the following equation for describing water and oil relative permeability curves versus IFT at  $S_w = 0.5$ :

$$k_{\rm rw}(S_{\rm w} = 0.5) = A_{\rm w}(\sigma_{\rm ow})^{\rm Bw}$$
 ( $r^2 = 0.7443$ ,  $F_{\rm stat} = 11.65$ ) (4)

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and

$$k_{\rm ro}(S_{\rm w} = 0.5) = A_{\rm o}(\sigma_{\rm ow})^{\rm Bo} \ (r^2 = 0.7405, \ F_{\rm stat} = 11.42),$$
 (5)

where  $k_{rw}(S_w=0.5)$  is the relative permeability to water phase at water saturation of 0.5;  $k_{ro}(S_w=0.5)$  is the relative permeability to oil phase at water saturation of 0.5; and  $A_w$ ,  $B_w$ ,  $A_o$ , and  $B_o$  are constants related to cores and experimental conditions.

Note that the results in Figs. 2 and 3 are consistent with the trends found in the literature (e.g., Fulcher et al. 1985).

#### 3.2 Normalized Relative Permeability

To analyze two-phase flow and displacement processes of various water-oil systems with different IFTs (e.g., for use in numerical simulation studies), we need complete relative permeability curves, not just their end values. Figure 4 shows such relative permeability curves, determined from our experimental measurements for two-phase flow, subject to different IFTs or under different capillary numbers. As the aqueous phase contains different amount of surfactants, significant differences exist in IFTs among the two-phase fluid systems. As a result, relative permeability curves obtained for different IFTs not only have very different end values, but also have very different shapes. This makes it difficult to compare and analyze experimental results for different IFTs.

In an effort to unify the experimental results, experimental data can be analyzed using the following normalized parameters and functions (Ahmed 2001). Normalized water saturation is defined as:

$$S_{\rm w}^* = \frac{S_{\rm w} - S_{\rm wc}}{1 - S_{\rm wc} - S_{\rm or}} \quad (0 \le S_{\rm w}^* \le 1) \tag{6}$$

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Fig. 5 Normalized water–oil relative permeability curves for different interfacial tension values (*Note*: legends list capillary numbers for corresponding curves)

Normalized relative permeability to water phase is defined as:

$$k_{\rm rw}^* = \frac{k_{\rm rw}}{(k_{\rm rw})_{S_{\rm or}}} \quad (0 \le k_{\rm rw}^* \le 1)$$
<sup>(7)</sup>

and normalized relative permeability to oil phase is:

$$k_{\rm ro}^* = \frac{k_{\rm ro}}{(k_{\rm ro})_{S_{\rm wc}}} \quad (0 \le k_{\rm ro}^* \le 1),$$
 (8)

where  $S_{\rm w}^*$  is the normalized wetting, aqueous phase saturation,  $k_{\rm rw}^*$  is the normalized aqueous-phase relative permeability,  $k_{\rm ro}^*$  is the normalized oil-phase relative permeability,  $(k_{\rm rw})_{S_{\rm or}}$  is the aqueous-phase relative permeability at residual oil-water saturation,  $(k_{\rm ro})_{S_{\rm wc}}$  is the oil-phase relative permeability at connate water saturation, and  $S_{\rm wc}$  is the connate water saturation.

Figure 5 shows the normalized relative permeability curves for two-phase flow using the same results in Fig. 4 for different capillary number or IFTs. It appears from Fig. 5 that after normalization, only small differences appear in both oil and water relative permeability curves for small capillary number (or large IFT  $\sigma > \sigma_{C1}$ ). Significant changes in normalized relative permeability curves occur as IFT changes when capillary number is large (or  $\sigma < \sigma_{C1}$ ).

### 3.3 Relative Permeability Model for Low Interfacial Tension

Many studies (e.g., Fulcher et al. 1985; Kumar et al. 1985; Brooks and Purcell 1952) have shown that water–oil relative permeability for two-phase flow systems is a function of fluid saturation, rock-pore characteristics, temperature, IFT, and capillary number. Even though a number of different forms of relative permeability functions have been proposed in the liter-

Table 3         Exponential indexes of relative permeability functions calibrated using the experimental data	$\sigma$ (mN/m)	n <sub>w</sub>	no	Sample number	
	34.2 Basis	4.428	2.289	4	
	water–oil system				
	3.52	4.298	2.148	2	
	0.21	2.788	1.749	4	
	0.0114	1.940	1.639	3	

ature, the simple exponential equation has perhaps been the most widely used relationship in reservoir simulation and groundwater modeling (Honarpour et al. 1986). In our experiment, water and oil viscosities and displacement rate remain constant for each experiment. Therefore, relative permeability from our experiments is considered as a function of saturation, IFT, and properties of core pores only. Based on the experimental measurements, we select the following two-phase flow relative permeability models:

$$k_{\rm rw} = m_{\rm w} (S_{\rm w}^*)^{n_{\rm w}} \tag{9}$$

and

$$k_{\rm ro} = m_{\rm o} (1 - S_{\rm w}^*)^{n_{\rm o}},\tag{10}$$

where  $m_w$  and  $m_o$  are coefficients of water and oil relative-permeability functions, respectively, and  $n_w$  and  $n_o$  are exponential constants or indexes of water and oil relative-permeability functions, respectively.

Note that  $m_w$  is the water relative permeability at  $S_w^* = 1$  and  $m_o$  is the oil relative permeability at  $S_w^* = 0$ , respectively. By definition, we have  $m_w = (k_{rw}^*)_{S_{or}}$  and  $m_o = (k_{ro}^*)_{S_{wc}}$ . Therefore, the normalized formula can be derived from Eqs. 9, 10 as

$$k_{\rm rw}^* = (S_{\rm w}^*)^{n_{\rm w}} \tag{11}$$

and

$$k_{\rm ro}^* = (1 - S_{\rm w}^*)^{n_{\rm o}} \tag{12}$$

Using the results of our experiments, the two exponential indexes,  $n_w$  and  $n_o$ , are found to be related to IFT and pore size distribution parameters,  $\lambda_w$  and  $\lambda_o$  (Brooks and Corey 1964), as

$$n_{\rm o} = n_{\rm o}(\sigma_{\rm wo}, \lambda_{\rm o}) \tag{13}$$

and

$$n_{\rm w} = n_{\rm w}(\sigma_{\rm wo}, \lambda_{\rm w}) \tag{14}$$

Based on a statistical analysis for the experimental data obtained with different IFT,  $n_w$  and  $n_o$  have been estimated as shown in Table 3.

Let us further discuss the role played by IFT in its impacting relative permeability curves. A recent study with an artificial neural network model (Silpngarmlers et al. 2002) indicates that for a given fluid system, relative permeability functions ( $k_r$ ) are closely related to the following groups of fluid and rock parameters as:

$$k_{\rm r} = f\left(\sigma_{\rm wo}S_{\rm wc}, \sigma_{\rm wo}S_{\rm or}, \ln(\sigma_{\rm wo}), \ln\left(\frac{\mu_{\rm w}}{\mu_{\rm o}\sigma_{\rm wo}}\right)\right),\tag{15}$$

Deringer



Fig. 6 Correlations between interfacial tension and exponential indexes,  $n_{\rm W}$  and  $n_{\rm O}$ 

where  $\mu_0$  is the viscosity of oil phase. Although neural network modeling cannot provide a closed-form function in general, it could help reveal the interrelationship between these parameters within two-phase flow permeability functions for a given fluid-rock system.

Based on our experimental data and curve-fitting results in Table 3, the particular relations between exponential constants and IFT can be written as:

$$n_{\rm o}(\sigma_{\rm wo}, \lambda_{\rm o}) = 0.1960 \times \log(\sigma_{\rm wo}) + \lambda_{\rm o} \quad (r = 0.9911)$$
 (16)

and

$$n_{\rm w}(\sigma_{\rm wo}, \lambda_{\rm w}) = 0.9371 \times \log(\sigma_{\rm wo}) + \lambda_{\rm w} \quad (r = 0.9975),$$
 (17)

where  $\lambda_w$  and  $\lambda_o$  are constants for water and oil relative permeability, respectively, for the same rock type. The two parameters,  $\lambda_w$  and  $\lambda_o$ , should be determined from pore properties of core samples, dependent on pore size distribution, tortuosity, and phase distribution within pores (wettability). With the sandstone outcrop cores associated with the fluids of this study, curve fitting of the experimental data leads to  $\lambda_w = 3.807$  and  $\lambda_o = 2.006$ .

Figure 6 shows the relationships between the two exponential indices and IFT. As shown in Fig. 6, IFT has an insignificant effect on  $n_w$  and  $n_o$ , when  $\sigma > \sigma_{C1}$  (3 mN/m), whereas for  $\sigma < \sigma_{C1}$  (3 mN/m), both water and oil exponential indices decrease with the decrease in IFT. However, the index,  $n_w$ , for the water phase decreases at a much larger rate. This is consistent with the observation of different relative permeability behavior for different ranges of IFT, separated by their crucial values. This indicates that lowering IFT has more impact on displacing aqueous phase flow than on flow of displaced oil, as discussed above.

It appears that as IFT decreases, two exponential indices also decrease. This will make both water and oil relative permeability curves tend to be straighter. As shown in Table 3 and Fig. 6, the exponential indices are still not close to one, even with a very low value of IFT ( $\sigma = 0.01$  mN/m). Therefore, the corresponding relative permeability curves are still not straight lines yet.

# 4 Summary and Concluding Remarks

This article presents an experimental study of two-phase relative permeability functions in a low IFT water–oil system. By carrying out the experiments and analyzing the experimental data, the following results and conclusions can be drawn:

- We have developed an improved steady-state method for measuring relative permeability data. This new steady-state method (with the designed experimental system) can be used to measure complete relative permeability curves under low IFT accurately and efficiently.
- 2. There appears to exist two crucial values or points ( $\sigma_{C1}$  and  $\sigma_{C2}$ ) in IFT that characterize IFT effects on relative permeability behavior and residual oil saturation for the systems of fluids and porous media used in this study.
- 3. Residual oil saturation tends toward zero as IFT are reduced as low as  $\sigma = 10^{-2}$  mN/m from  $\sigma = 3$  mN/m. In addition, relative permeability curves for both water and oil phases become less curved, i.e., becoming straighter with decreasing IFT.
- 4. For  $\sigma > 3 (\sigma_{C1})$  mN/m, IFT shows little impact on both residual oil saturation and relative permeability values for water and oil at  $S_w = 0.5$ .
- 5. For  $\sigma > \sigma_{C1}$ , two-phase flow and displacement can be handled as normal brine-oil flow. However, once  $\sigma < \sigma_{C1}$ , two-phase flow behaves very differently, and the effects of IFT must be considered in relative permeability models. As IFT decreases to lower than the second crucial point (i.e.,  $\sigma < \sigma_{C2}$ ), relative-permeability-curve shapes will continuously change, even though residual oil saturation and relative permeability values at  $S_{\rm w} = 0.5$  will hardly change at all.
- 6. The experimental data and their analysis indicate that relative permeability for the low IFT water–oil system is described by a function having the form:  $k_r = S_w^{*A \log \sigma_{wo} + \lambda}$ .

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